Available online at www.sciencedirect.com

ScienceDirect

Energy Procedia 4 (2011) 2005–2019

Energy Procedia

www.elsevier.com/locate/procedia

GHGT-10

Impact of post combustion capture of CO_2 on existing and new Australian coal-fired power plants

N. Dave1*, T. Do, D. Palfreyman and P.H.M. Feron

CSIRO Energy Technology, 11 Julius Av., North Ryde 2113, Australia

Abstract

Currently, Australia emits approximately 600 MT equivalent of CO_2 annually, of which approximately 30% is directly linked to the electricity generation using both brown and black coals. To restrain the CO_2 emissions, coal based power generators are looking to retrofit the existing power plants with commercially available technology for the post combustion capture (PCC) of CO_2 as well as invest in the new power plants with high efficiency steam cycles.

Since Australian coals are low in sulphur and the coal-fired power plants are well away from densely populated regions, the flue gas desulphurisation (FGD) and de-NO_X regulations are currently not there for the coal based electricity generation in Australia. This is not an advantageous situation for straightforward retrofitting of the existing power plants with 30 wt% aqueous MEA based commercially available PCC technology that has very limited tolerance for SO_X and NO_X (less than 10 ppmv). In addition, Australia is a dry continent with very limited cooling water availability for the power plants. Hence, the Australian power generators are considering both the power and the post combustion CO_2 capture plants to be air cooled.

This paper, therefore, assesses the impact of introducing post combustion capture of CO_2 on the existing and new Australian coal-fired power plants, both brown and black coal-fired, in terms of the cost of electricity generation, the cost of CO_2 avoidance, the cooling water demand and the overall plant efficiency. The existing power plants are considered to be conventional subcritical and supercritical single reheat steam cycle based whereas the new power plant designs have allowed for ultracritical steam conditions (35 MPa, 922 K) with double reheat. The CO_2 capture plants are considered to be either in service full time or in service on demand with 90% capture efficiency and the product CO_2 ready for sequestration at 10 MPa and 313 K. The process and cost models for integrated power and capture plants have been obtained using ASPEN Rate-Sep, Steam-Pro, Steam-Master and PEACE software packages for process modelling and cost estimation.

The results clearly show that an air cooled integrated power and capture plant has lower overall plant efficiency and slightly higher cost of electricity generation in comparison with a water cooled equivalent plant. An ultracritical single reheat power plant when integrated with capture plant that is in service full time has potential for lowest cost of electricity generation with minimum cost for CO_2 avoidance. These results further show that replacing an existing turbine with a new LP turbine optimised for continuous steam extraction for CO_2 plant duty minimises the adverse impact of PCC integration but the power generator looses the flexibility for electricity generation.

* Corresponding author. Tel.:+61-2-94905306; fax: +61-2-94908530.
E-mail address: narendra.dave@csiro.au

doi:10.1016/j.egypro.2011.02.082

The results also provide important insights into the major contributions to the increased cost of power generation. For both the existing and the new power plants, the amortised capital charge component dominates the cost of PCC integrated electricity generation. In spite of the large reduction in efficiency for Australian power plants when PCC is applied, it appears that reducing the capital costs of PCC will be at least equally important. This is an important outcome for the prioritization of research activities aimed at reducing the costs of capture. For example, the novel solvent development work for improved PCC technology should focus on increasing absorption rates at the same CO_2 carrying capacity of the solvent to reduce the capital cost component.

Keywords: CO2 Capture, PCC Integration and Economics, Carbon Capture, Greenhouse Gas Mitigation

1. Introduction

It is well known that coal-fired power stations are the largest point sources of carbon dioxide emissions that are contributing to the global warming. In Australia alone, the power generators produce around 170 Mtonne of CO_2 emissions per annum or over 40% of Australia's anthropogenic CO_2 emissions using the black and brown coals that accounts for 170 TWh per annum of electricity [1]. Whilst this level of electricity production currently brings significant economic benefits to Australia, there is a growing realisation both at the state and federal government levels that in order to maintain current economic prosperity in future with minimal adverse climatic impact of large scale CO_2 emissions, the post combustion capture of CO_2 and its geological storage will seriously need to be implemented at the earliest. Although several different processes are currently under development for the separation of CO_2 from flue gases, absorption processes using aqueous solutions of chemical absorbents is the leading technology. The typical flow sheet of CO_2 separation and recovery process using chemical absorbents is shown in Figure 1 [9].

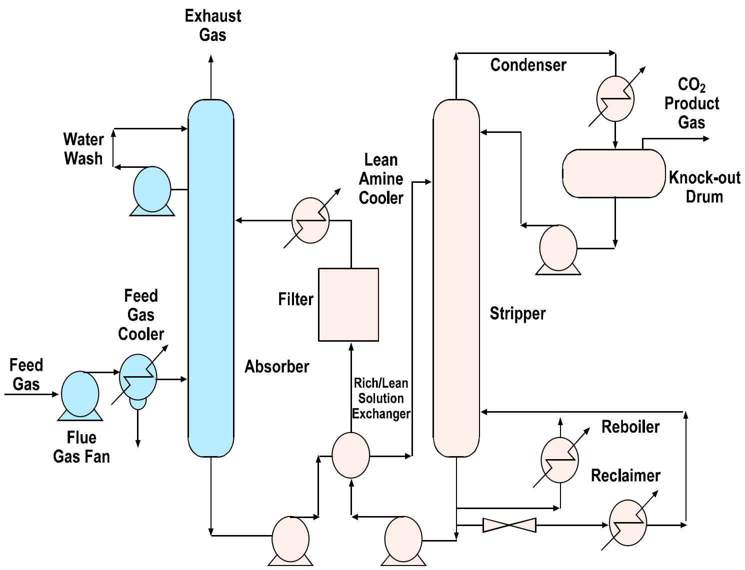


Figure 1: Process flow diagram for CO_2 recovery from flue gas with chemical absorbents

Whilst commercially available aqueous MEA (monoethanolamine) solvent based post-combustion CO_2 capture (PCC) technology promises large scale carbon dioxide emissions reductions when implemented in the power plant sector, this technology is known to reduce the power plant efficiency and thereby increase the cost of producing electricity. In addition, the standard aqueous MEA solvent has poor SO_X/NO_X tolerance and hence necessitates flue gas desulphurisation (FGD) which imposes additional capital and operating expenditure burden on the Australian power generators who currently do not have statutory requirement for FGD.

In addition to limited availability of water (Australia being a dry continent) and lack of emission controls other than particulate removal in Australian power plants, the deployment issues with chemical solvent based PCC processes such as high costs, increased cooling water demand, limited knowledge of environmental impact, lack of scale-up experience and limited understanding of operational dynamics resulting from process integration with power plants are well documented [7]. These issues have raised the need for an update of the expected techno-economic impact of integrating the MEA based PCC process with coal-fired power plants in Australia as the first preliminary assessment was done over a decade ago [4]. The detailed assessment results could also be used to provide justification for focus of research directions of particular relevance to Australia. This paper describes the methodology and results of a techno-economic evaluation of liquid absorption based post-combustion capture processes for both existing and new pulverised coal-fired power stations in Australia. The overall process design incorporates flexibility with switching a CO_2 capture plant ON or OFF depending upon the demand and market price for electricity, and addresses the impact of the presently limited emission controls on the process cost. The techno-economic evaluation includes both air and water cooled power and CO_2 capture plants, resulting in cost of generation for the situations without and with PCC.

2. Methodology

For black coal-fired power plant, a generic plant with gross electrical power output of 600 MW and operating at 85% capacity factor was assumed for this study. The power plant uses Surat Basin (Queensland) black coal, the composition of which is given in Table 1. The ambient conditions for this plant were in accordance with the "Technical Guidelines - Generator Efficiency Standards" (GES) released by the Australian Government [2]. Table 2 summarises these conditions.

Table 1: Surat Basin black coal properties

Proximate Analysis (weight % as received)	
Moisture	12.4
Ash	25.4
Volatile Matter	33.3
Fixed Carbon	28.7
Total	99.8
Heating Value (as received)	
HHV (MJ/kg)	20.14
Ultimate Analysis (weight % dry ash free)	
Carbon	76.5
Hydrogen	6.45
Nitrogen	0.95
Sulphur	0.53
Oxygen	15.57
Total	100.0
Performance	
Unburnt carbon in furnace ash (%)	5
Unburnt carbon in fly-ash (%)	1.7

Table 2: Ambient conditions (GES) for black coal-fired power plants

Temperature (K)	298.15
Altitude (m)	111
Pressure (Bar)	1.0
Relative Humidity (%)	60
Wet Bulb Temperature (K)	292.65
Cooling Water Temperature (K)	292.65

Whilst existing black coal-fired power plants in Australia are almost entirely subcritical type, supercritical single reheat conditions have been applied recently, and other higher efficiency steam cycles are expected to be applied in future to all black coal-fired plants larger than about 350 MW in capacity. Hence, in this study the steam cycles and the steam conditions for black coal-fired power plants were varied as below:

1. Subcritical – 16 MPa/811 K & 3.9 MPa/811 K
2. Supercritical Single Reheat – 25 MPa/839 K & 4.4 MPa/839 K
3. Ultra-supercritical Single Reheat – 27.5 MPa/878 K and 5.7 MPa/886 K
4. Supercritical Double Reheat – 25 MPa/839 K, 6.6 MPa/839 K & 1.9 MPa/839 K
5. Ultra-supercritical Double Reheat – 34.6 MPa/922 K, 9.5 MPa/922 K & 2.6 MPa/922 K

For brown coal-fired power plant, a generic sub-critical, but natural draft wet cooled power plant with gross electrical power output of 539 MW and operating at 85% capacity factor was assumed. This plant was assumed to use a typical Australian brown coal with 62% w/w moisture as received and practise typical pre-drying steps followed in Australian power plants to have moisture content at the furnace inlet at 20% w/w. Table 3 gives the flue gas composition, flow rate and temperature for this power plant whereas Table 4 lists the ambient conditions applicable to this plant.

Table 3: Flue gas data for the brown coal-fired power plant

Flue gas flow rate (tonnes/hr)	3000.7
Flue gas temperature (^oK)	441.5
Composition (volume %):	
N_2	58.8
O_2	3.2
CO_2	11.8
H_2O	25.5
Ar	0.7
SO_X (ppmv)	273
NO_X (ppmv)	200

Table 4 - Ambient conditions for the brown coal-fired power plant

Temperature (K)	291.15
Altitude (m)	0
Pressure (Bar)	1.0
Relative Humidity (%)	73
Wet Bulb Temperature (K)	288.15
Cooling Water Approach Temperature to Wet Bulb Temperature (K)	12.6

With the above operating conditions, STEAM PRO, STEAM MASTER and PEACE software from Thermoflex Inc were used as the state-of-the-art tools to simulate both the brown and black coal-fired power plants. STEAM PRO allows for the steam plant design point heat balances, complete with outputs for plant hardware description, preliminary engineering details and cost estimates in conjunction with PEACE. Hence, it realistically simulates and costs a base case coal-fired power plant without CO_2 capture. STEAM MASTER facilitates off-design calculations for an existing power plant and hence estimates the impact of steam extraction on the power plant performance when steam is extracted from the steam cycle in order to regenerate the spent chemical solvent in the stripper of CO_2 capture plant. March 2008 versions of these softwares were used for this study and hence the coal-fired power plant capital investment costs with and without CO_2 capture were obtained for the period ending first quarter of 2008. It should be noted that these costs are calculated by the PEACE software in US currency. For the period ending first quarter of 2008, the Australian currency (Aus $) was close to parity with the US currency (US $). As a result, the cost data are reported for this study in Australian currency.

The CO_2 capture plant was simulated using the ASPEN-Plus process engineering software available from AspenTech Inc, USA. This software provides steady state chemical equilibrium based as well as reaction kinetics based process designs for the CO_2 absorber and the solvent regenerator. In addition, material and energy flows are determined at inlets and outlets of all equipment on the CO_2 capture plant to facilitate their sizing. For the base case, 30% w/w MEA (monoethanolamine) based CO_2 capture process was envisaged. Table 5 details the operating conditions determined for the CO_2 capture plant. The CO_2 capture plant was considered to have 2 parallel trains of absorbers and 2 parallel trains of solvent regenerators. The steam for solvent regeneration was considered to be available from the power plant steam cycle at 305 kPa and 406 K. The capture plant capital investment cost was calculated from in-house data and verified against the public domain cost data available from the past studies for similar size plant [5, 10, 12].

For the power plant and CO_2 capture plant operating cost calculations, the following assumptions were made:

- Power plant capacity factor - 85%
- Existing power plant is fully amortised.
- Fuel cost (as received) – Aus $0.5/GJ for brown coal and AUS $1/GJ for black coal
- Cost of electricity for CO_2 capture and compression – At amortised capital price
- Construction period for CO_2 capture plant and a new power plant – 3 years
- 30 wt% aqueous MEA for CO_2 capture and capture efficiency at 90%
- Annual interest rate - 10%
- Amortisation period for CO_2 capture plant – 30 years

Whilst coal based projects can have technical life time of up to 40 years when midlife refits are considered, for the present study the life time was kept at 30 years in accordance with the Australian Tax Office ruling TR2006/5, "Effective life of depreciating assets". The annual costs of raw, process and cooling water usage, chemicals consumed, solid and liquid waste disposal, plant manning, maintenance and administration applicable to both the power and the CO_2 capture plants were calculated as per the CSIRO's in-house data. Other soft operating costs such as the annual insurance liability against natural and man made disasters, local, state and federal level taxes, etc. were excluded from the techno-economic assessment.

Table 5: Operating conditions for CO_2 capture plant

Chemical Solvent – Aqueous MEA	30% w/w
Solvent Temperature @ Inlet to the Absorber	313.15 K
Flue Gas Temperature @ Inlet to the Absorber	318.15 K
CO_2 Loading of Solvent @ Inlet to the Absorber	0.21
CO_2 Removal and Recovery Rate	90%
Number of Theoretical Stages in Absorber	4
Number of Theoretical Stages in Regenerator	9
Reboiler Temperature	399.15 K
Reboiler Heat Duty per kg of CO_2 Recovered	4 MJ
Product CO_2 Pressure and Temperature	10 MPa and 313.15 K

3. Process Simulations

Figure 2 shows the process flow-sheet for a mechanical draft wet cooled subcritical pf-fired power plant (600 MW gross) as developed by the STEAM PRO software for the Australian situation. It shows that the steam system consists of a single high pressure turbine (HPT), a single twin path intermediate pressure turbine (IPT) and 2 twin path low pressure turbines (LPT). Steam bleed points are provided on the turbines for steam extraction for feed water heating. The feed water heating system consists of a single Low Pressure (LP) train, a single de-aerator and two symmetrical High Pressure (HP) trains. The LP train starts with a single external drain cooler, followed by 2 low pressure flash back heaters (F). Following this are 2 flash back heaters with internal drain coolers (D). Following the low pressure feed water train, there is a single contact type heater (C) operating as the deaerator. Each High Pressure train consists of 2 flash back heaters with internal drain coolers (D). The steam and feed water heating system described so far was also used for the natural draft wet cooled subcritical brown coal-fired power plant simulation.

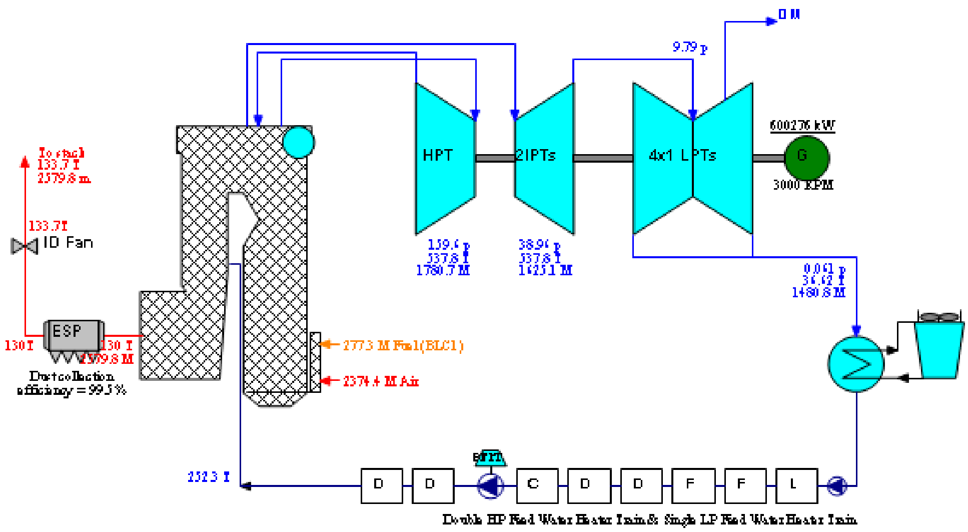


Figure 2: Flow sheet for mechanical draft wet cooled coal-fired subcritical power plant

The subcritical plant simulations showed that if Surat basin black coal is used as fuel with 20% by volume excess air, then the flue gas leaving the stack will have approximately 320 ppmV SO_X and 44 mg/Nm^3 of particulate material. With brown coal as fuel and excess air level for combustion such that the flue gas has 6% oxygen by volume, the flue gas leaving the stack was determined to have approximately 273 ppmv SO_X and in excess of 70 mg/Nm^3 of particulate material. The current generation of CO_2 capture technology that uses 30% w/w MEA solvent is intolerant to SO_X and particulate content greater than 10 ppmV and 10 mg/Nm^3 respectively [11]. As a result, the implementation of CO_2 capture process in Australia definitely requires the flue gas desulphurisation (FGD) unit upstream. Improved FGD-technologies are available to achieve such low levels [6]. STEAM PRO calculates additional electrical power consumption, limestone/lime usage and capital investment associated with incorporation of the FGD unit for Australian power plants. Similar to the subcritical plant case, STEAM PRO process flow sheets and capital investment costs were calculated for other plant cases as well.

The generic process flow sheet (Figure 1) for a typical 30% w/w MEA based CO_2 capture process was simulated using the ASPEN-Plus Rate-Sep software. After in-direct heat exchange with the CO_2 lean exhaust gas leaving the absorber, the flue gas (Feed Gas) is pumped into the absorber by a blower. A direct contact type feed gas cooler upstream of the absorber controls the gas temperature at the absorber inlet. This feed gas cooler was envisaged to use 2% w/w aqueous soda solution to control SO_X levels in the feed gas to the absorber below 10 ppmV. After passing through the absorber the flue gas undergoes a water wash section to remove any solvent droplets carried over and then leaves the absorber. The "CO_2 rich" absorbent solution is pumped to the top of a stripper, via a heat exchanger. The regeneration of the solvent is carried out in the stripper. Heat is supplied to the reboiler to maintain the regeneration conditions. The CO_2 product gas leaves the stripper via an overhead condenser. The CO_2-product is a relatively pure product, with water vapour being the main other component. It is first dehydrated to less than 50 ppmV moisture and compressed to 10 MPa and 313 K in the sequestration ready form using four stage water cooled compressor with 2.7 compression ratio. The "CO_2 lean" absorbent solution, containing far less CO_2 is then pumped back to the absorber via the lean-rich heat exchanger and a cooler to bring it down to the absorber temperature level.

It is envisaged that the CO_2 capture plant could be considered to operate in two different modes viz., continuously or In Service full time, and ON/OFF or In Service on Demand only. In the first case, the power plant is constantly required to meet the CO_2 emissions reduction target whereas in the later case, a power generator has flexibility to turn OFF the CO_2 capture plant when the electricity demand and its sell price in the spot electricity market is sufficiently high and switch ON the capture plant when such conditions are not met. In case of CO_2 capture large heat loads associated with the overhead condenser and the reboiler on CO_2 stripper, the lean amine trim cooler and the intercoolers associated with CO_2 compression provide common nodes for integrating a pf-fired power plant with a CO_2 capture plant. For existing power plants in Australia, retrofitting CO_2 capture plant involves extracting steam at 305 kPa either from one of the appropriate ports on LP turbine or installing a throttle valve at IP/LP turbine crossover, if the power generators require operational flexibility with CO_2 capture plant. Unfortunately, the first option causes de-rating of LP turbine and possibly stability problems with turbine when the capture plant is switched on. If the capture plant is to be in service full time, the preferred option for the power generator could be the replacement of existing LP turbine with a new appropriate capacity (smaller) LP turbine. For the cost estimation purposes in this study, the existing turbine when replaced, it was considered to fetch 10% value of the new turbine as scrap. For a new power plant where integration of a CO_2 capture plant can be considered at the design stage of the power plant, incorporation of a back pressure turbine at IP/LP crossover is an alternative and accordingly steam extraction from IP/LP crossover via back pressure turbine that kept extracted steam pressure at 305kPa was considered in the process simulation. For this study, steam extracted from the steam cycle for both existing and new power plants to meet the reboiler duty of CO_2 stripper is first cooled down to 406 K by injecting boiler feed water in it before diverting to the reboiler and the condensate leaving the reboiler is returned the boiler feed water circuit. In order to optimise the integration of power plant with a CO_2 capture plant, the CO_2 stripper condenser and the CO_2 compression intercoolers are cooled by the boiler feed water.

Since Australia has limitations in the available utility cooling water particularly at inland locations, the power generators are seeking to incorporate dry cooling (ambient air as coolant) both in the power plant and the CO_2 capture plant. Conventional dry cooling for the overhead condenser on the CO_2 stripper and the intercoolers on a multistage CO_2 compressor involves large heat exchangers sizes, pressure loss on the process fluid side and fan power; all of which could have adverse techno-economic impact. Thus for the CO_2 capture plant, the dry cooling was restricted in this study to cooling the utility water in a heat exchanger which is air cooled using a fan. The power consumption by this fan was calculated by Steam Pro and the cost of air cooled heat exchanger was obtained from Jord International Ltd (Australia), an equipment vendor, for various power plant and capture plant integration scenarios. Based on these considerations eight combinations of the power plant and the CO_2 capture plant have been investigated in this study as below.

Case 1

New black coal-fired subcritical, supercritical single reheat (Super-1RH), ultra-supercritical single reheat (Ultrasuper-1RH), supercritical double reheat (Super-2RH) and ultra-supercritical double reheat (Ultrasuper-2RH) power plants without CO_2 capture and with CO_2 capture plants full time in service. Both the power plant and the capture plant are mechanical draft wet cooled.

Case 2

New black coal-fired subcritical, supercritical single reheat (Super-1RH), ultra-supercritical single reheat (Ultrasuper-1RH), supercritical double reheat (Super-2RH) and ultra-supercritical double reheat (Ultrasuper-2RH) power plants with CO_2 capture plants ON/OFF on demand. Both the power plant and the capture plant are mechanical draft wet cooled.

Case 3

New black coal-fired subcritical, supercritical single reheat (Super-1RH), ultra-supercritical single reheat (Ultrasuper-1RH), supercritical double reheat (Super-2RH) and ultra-supercritical double reheat (Ultrasuper-2RH) power plants without CO_2 capture and with CO_2 capture plants full time ON. Both the power plant and the capture plant are air cooled.

Case 4

New black coal-fired subcritical, supercritical single reheat (Super-1RH), ultra-supercritical single reheat (Ultrasuper-1RH), supercritical double reheat (Super-2RH) and ultra-supercritical double reheat (Ultrasuper-2RH) power plants with CO_2 capture plants ON/OFF on demand. Both the power plant and the capture plant are air cooled.

Case 5

Existing black coal-fired subcritical and supercritical single reheat (Super-1RH) power plants without CO_2 capture and with CO_2 capture plant ON/OFF on demand. Both the power plant and the capture plant are mechanical draft wet cooled with the steam cycle not modified for capture.

Case 6

Existing black coal-fired subcritical and supercritical single reheat (Super-1RH) power plants with CO_2 capture plants full time ON. Both the power plant and the capture plant are mechanical draft wet cooled with new LP turbine in the steam cycle for capture.

Case 7

Existing black coal-fired subcritical and supercritical single reheat (Super-1RH) power plants with CO_2 capture plants ON/OFF on demand. Both the power plant and the capture plant are mechanical draft wet cooled with a throttle valve at the IP/LP crossover in the steam cycle for capture.

Case 8

Existing natural draft wet cooled brown coal-fired subcritical power plant without CO_2 capture and with CO_2 capture plant ON/OFF on demand. The power plant steam turbines have a throttle valve at the IP/LP crossover for capture and the capture plant is dry air cooled.

In each of the above cases, limestone/lime slurry based FGD unit with 98.5% efficiency was embedded in the power plant for facilitating aqueous 30% w/w MEA based CO_2 capture and the capture plant was fully integrated with the power plant through the heat load nodes at the CO_2 stripper reboiler, the stripper overhead condenser, the lean amine trim cooler and the CO_2 compressor intercoolers. For all cases of the water cooled black coal-fired power plants, the steam condenser design pressure on the process side was kept at 6.1 kPa where as in the air cooled cases, it was kept at 12.2 kPa. For the natural draft wet cooled brown coal-fired power plant the steam condenser design pressure was 5 kPa. The values for other operating parameters associated with the power plant functioning that are used for power plant simulations such as the primary and secondary air cold and hot end leakage rates, cold cooling water approach temperature to ambient wet bulb temperature, cold cooling water temperature rise in the steam condenser, hot cooling water approach temperature of the condensate, air to water ratio in the cooling tower, temperature rise for air over steam condenser etc are documented in the CSIRO Energy Technology reports [13, 14].

Using the material and energy balance and the capital and operating cost estimates derived through the process simulations for each integrated case of the power and capture plants, impact of 30% w/w aqueous MEA based PCC process on the power plant net efficiency, the cost of electricity generation and the cost of CO_2 avoidance ($ per ton of CO_2 avoided) was calculated. The cost of CO_2 avoidance was evaluated with reference to the same power plant type without CO_2 capture.

4. Results and Discussion

Tables 6 to 8 show the calculated performance of new black coal-fired power plants in Australian context with and without 90% CO_2 capture plants integrated (Cases 1 to 4). These results show that the air cooled power plants have about 1 to 1.5% (absolute points) lower net efficiency than the wet cooled power plants and consequently about Aus $1.5 per MWh_{net} (net power output) higher cost of electricity generation. When CO_2 capture is implemented in these plants, their net efficiency drops approximately 10% (absolute points) and the cost of electricity generation more than doubles across the board. Where the power generator has flexibility to switch the capture plant on and off on demand (flexible operation), the overall plant efficiency is lower than the case where the capture plant is ON full time. This is also reflected in the higher cost of electricity generation and CO_2 avoidance for these plants. The results clearly show that irrespective of flexibility with CO_2 capture, an ultra-supercritical single reheat (ultrasuper-1RH) power plant has potential for the lowest cost of electricity generation (Aus $104 to 108 per MWh_{net}) and CO_2 avoidance (roughly AUS $88 per tonne of CO_2) when capture is implemented.

Table 6: Impact of PCC integration on net plant efficiency (%HHV) for new black coal-fired plants

Power Plant Type	Water Cooled Plant			Air Cooled Plant		
	No Capture	Capture on Full Time	Capture on Demand	No Capture	Capture on Full Time	Capture on Demand
Subcritical	36.7%	26.7%	26.0%	35.2%	25.7%	25.2%
Super-1RH	39.2%	29.1%	27.9%	37.7%	28.0%	27.2%
Ultrasuper-1RH	40.3%	30.1%	28.9%	38.8%	29.1%	28.1%
Super-2RH	39.7%	29.3%	28.1%	38.2%	28.0%	27.3%
Ultrasuper-2RH	41.2%	30.3%	28.7%	39.8%	29.3%	28.3%

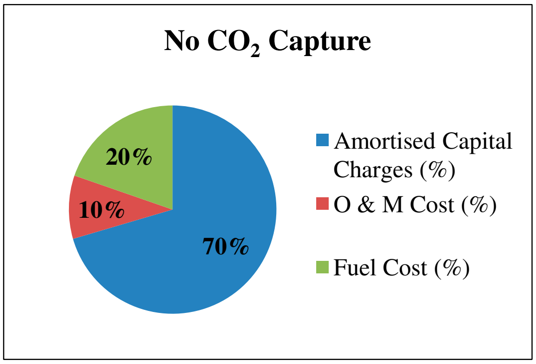
Table 7: Impact of PCC integration on the cost of electricity generation (Aus $/$MWh_{net}$) for new black coal-fired plants

Power Plant Type	Water Cooled Plant			Air Cooled Plant		
	No Capture	Capture on Full Time	Capture on Demand	No Capture	Capture on Full Time	Capture on Demand
Subcritical	46.3	104.3	109.9	48.0	108.5	114.6
Super-1RH	45.7	99.0	106.0	47.3	103.2	110.2
Ultrasuper-1RH	45.6	97.4	104.1	47.1	101.1	108.1
Super-2RH	44.3	97.6	105.9	45.7	102.0	109.8
Ultrasuper-2RH	47.9	102.4	105.0	49.3	106.5	115.2

Table 8: Impact of PCC integration on the CO_2 avoidance cost (Aus $/tonne of CO_2) for new black coal-fired plants

Power Plant Type	Water Cooled Plant			Air Cooled Plant		
	No Capture	Capture on Full Time	Capture on Demand	No Capture	Capture on Full Time	Capture on Demand
Subcritical	N/A	79.4	87.2	N/A	79.4	87.4
Super-1RH	N/A	77.7	88.6	N/A	78.4	89.3
Ultrasuper-1RH	N/A	77.4	88.1	N/A	77.8	88.2
Super-2RH	N/A	79.0	91.7	N/A	80.2	92.2
Ultrasuper-2RH	N/A	82.9	96.4	N/A	84.0	97.2

Figure 3 shows the break down of cost of electricity generation for new mechanical draft water cooled ultra-supercritical single reheat (ultrasuper-1RH) power plant without CO_2 capture and with flexible capture. It is clearly evident that the capital costs associated with the power plant and the capture plant dominate the cost of electricity generation. This is also the case where the capture plant is operating continuously. For an equivalent air cooled power plant with and without capture similar results were obtained. For other types of air and water cooled new power plants, both without and with post combustion capture, the contribution of amortised capital charges to the cost of electricity generation remained in the range 66% to 70%.



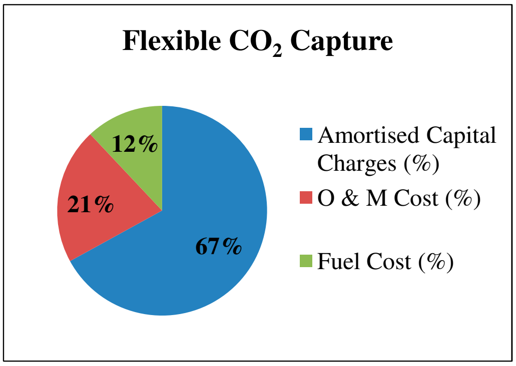


Figure 3: Breakdown of the cost of electricity generation for a new ultra-supercritical single reheat (ultrasuper-1RH) black coal-fired power plant without and with CO_2 Capture

Tables 9 to 11 below show the likely performance of existing mechanical draft wet cooled subcritical and supercritical single reheat (Super-1RH) black coal-fired power plants in Australian context with and without 90% CO_2 capture plants integrated (Cases 5 to 7) according to Steam Pro, Steam Master, Peace and Aspen Plus simulations. These results clearly show that under the 90% CO_2 capture scenario, an existing power plant has lowest impact on its net efficiency, cost of electricity generation and cost of CO_2 avoidance when retrofitted with a new LP turbine and a capture plant that is full time running. Replacing existing turbine with a new LP turbine optimised for continuous steam extraction for the capture plant duty minimises the adverse impact of PCC integration but the power generator looses electricity generation flexibility. For the subcritical power plant, the marginal cost of electricity in this case rises from Aus \$14.6/MWh$_{net}$ for no capture to Aus \$56.6/MWh$_{net}$ with capture and the cost of CO_2 avoidance becomes Aus \$60/tonne of CO_2. For the supercritical single reheat power plant, its cost of electricity rises from Aus \$13.8/ MWh$_{net}$ for no capture to Aus \$52.6/MWh$_{net}$ with capture and the cost of CO_2 avoidance becomes Aus \$56.7/tonne of CO_2. It should be noted that for the existing power plants the residual capital value of the power plant is assumed zero and hence the marginal cost of electricity generation is around Aus \$14 to 15 per net MWh power output. However in reality, the power generators always attach a certain capital value to their asset and depending upon their financing arrangements may have certain capital debt to be paid off during the life time of operation. However, the assumption of the existing plant fully amortised gives a lowest bound to the cost of electricity generation when such plants are retrofitted for capture.

Table 9 – Impact of PCC integration on net plant efficiency (%HHV) for existing mechanical draft water cooled black coal-fired plants

Plant Type	**Net Plant Efficiency (% HHV)**			
	No Capture	**No Modifications**	**New LP Turbine**	**Throttle Valve**
		Capture ON Demand	**Capture ON Full Time**	**Capture on Demand**
Subcritical	36.5	26.1	26.9	26.1
Super-1RH	39.2	28.0	29.2	28.0

Table 10 – Impact of PCC integration on the cost of electricity generation (Aus \$/MWh$_{net}$) for existing mechanical draft water cooled black coal-fired plants

Plant Type	**Cost of Electricity Generation (Aus \$/MWh$_{net}$)**			
	No Capture	**No Modifications**	**New LP Turbine**	**Throttle Valve**
		Capture ON Demand	**Capture ON Full Time**	**Capture on Demand**
Subcritical	14.6	58.0	56.6	58.3
Super-1RH	13.8	54.5	52.6	54.7

Table 11: Impact of PCC integration on the CO_2 avoidance cost (Aus\$/tonne of CO_2) for existing mechanical draft water cooled black coal-fired plants

Plant Type	**CO_2 Avoidance Cost (Aus \$/tonne of CO_2)**			
	No Capture	**No Modifications**	**New LP Turbine**	**Throttle Valve**
		Capture on Demand	**Capture on Full Time**	**Capture on Demand**
Subcritical	N/A	59.7	57.5	60.0
Super-1RH	N/A	59.6	56.7	59.9

Figure 4 below shows that the capture plant capital costs will dominate the cost of electricity generation for the existing black coal-fired subcritical power plants with PCC integration. In particular this relates to the amortised capital charges associated with installing the FGD system, the steam extraction valve at the IP/LP crossover in the steam cycle and the capture plant. Therefore, the technology development efforts should not only be directed at developing novel solvents for reducing the energy efficiency impact of CO_2 capture but also towards reducing the capital cost of the FGD system and the capture plant. This can be achieved for instance by using more reactive solvents.

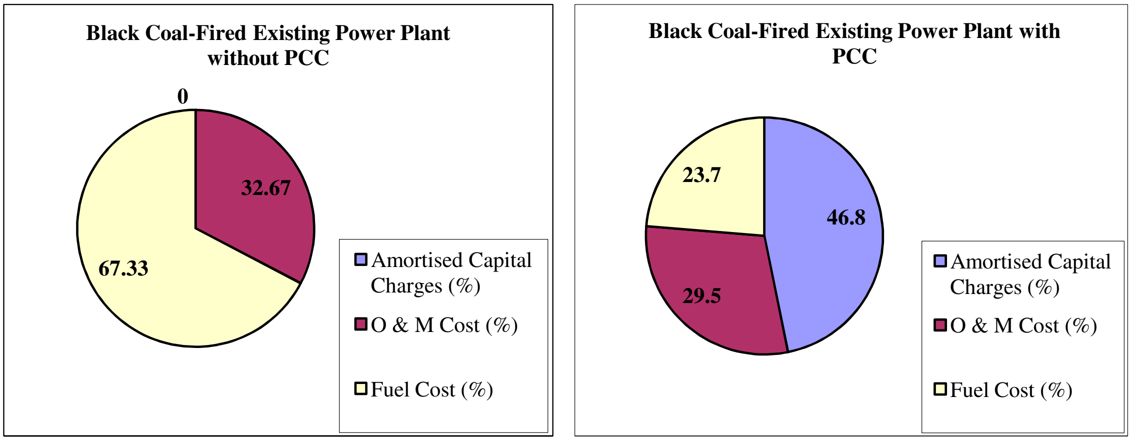


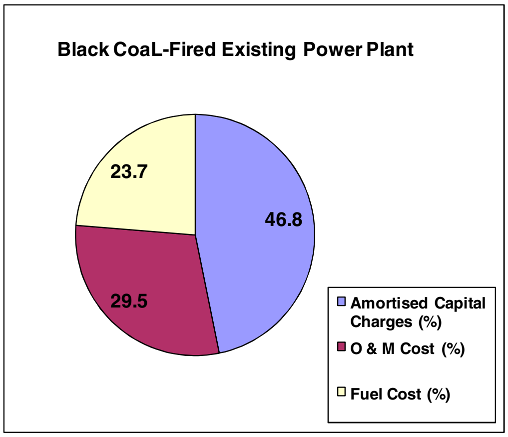
Figure 4: Breakdown of the cost of electricity generation for existing subcritical power plants

Table 12 given below shows the impact of integrating 30% w/w aqueous MEA based PCC technology with an existing natural draft wet cooled brown coal-fired subcritical power plant where 90% CO_2 capture is desired with the power plant having flexibility to switch ON and OFF the capture plant on demand (Case 8). In this case, a throttle valve is used at the IP/LP crossover in the steam cycle for steam delivery to the capture plant when it is ON and air cooled heat exchanger system is used to pick up the utility water cooling load. The power plant is assumed to be retrofitted with limestone/lime based FGD system to meet the SO_X limits of the PCC technology. Table 12 also compares performance of this power plant with that of a mechanical draft wet cooled black coal-fired subcritical power plant that has an IP/LP crossover integrated water cooled 90% capture plant operating ON/OFF on demand. The results clearly show higher costs of electricity generation and CO_2 avoidance for a brown coal-fired subcritical power plant in comparison with a black coal-fired subcritical power plant when PCC integration is implemented.

Table 12 – Comparison of PCC integrated existing brown and black coal-fired power plants

Plant Performance	Brown Coal Plant	Black Coal Plant
Net Efficiency (%HHV) Without Capture	28.9	36.5
Net Efficiency (%HHV) With 90% Capture	17.1	26.1
Cost of Electricity Generation Without Capture (Aus $/MWh$_{net}$)	11.1	14.6
Cost of Electricity Generation With Capture (Aus $/MWh$_{net}$)	83.0	58.3
Cost of CO_2 Avoidance (Aus $/tonne of CO_2)	74.9	60.0

Figure 5 below shows that for the existing brown coal-fired subcritical power plants with PCC integration, it is the amortised capital charges associated with installing the FGD system, the steam extraction valve at the IP/LP crossover in the steam cycle and the capture plant dominate the cost of electricity generation just as is the case with the existing black coal-fired power plants. Therefore, for these plants too the technology development efforts should be directed at not only developing the novel solvents for reducing the energy efficiency impact of CO_2 capture but towards reducing the fixed capital cost of the FGD system and the capture plant as well.



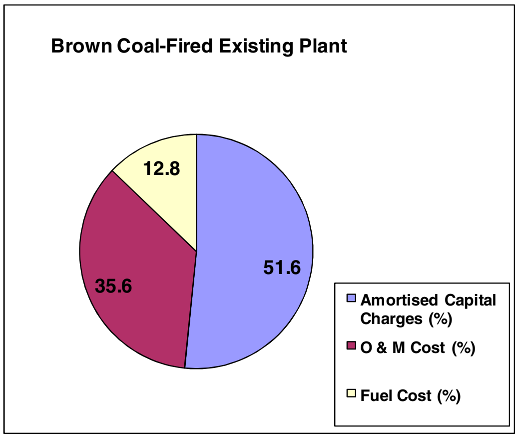


Figure 5: Breakdown of the cost of electricity generation for subcritical power plants with PCC

5. Conclusion

Techno-economic assessment of integrating post combustion capture with existing and in future to be installed coal-fired power plants for Australia clearly show that there are large efficiency and cost penalties associated with introducing CO_2 capture for its emission reduction. The process simulations for both water cooled and air cooled power plants indicate that the later type of power plants will have marginally lower net plant efficiency and higher cost of electricity generation with and without CO_2 capture compared to their water cooled equivalents. Hence, the cost of CO_2 avoidance for these plants will also be relatively higher. This is valid irrespective of whether the capture plant is operated continuously or flexibly allowing for switching on/off. Should the post combustion capture of CO_2 become mandatory in future, then the ultra-supercritical single reheat design of power plants will become a preferred option for new plants in Australia, since they have potential to generate electricity at lowest cost with the lowest cost of CO_2 avoidance. The cost of electricity generation for such plants will be dominated by the capital amortisation charges that are likely to be roughly 70% of the cost of electricity generation under the assumptions made in this study. Retrofitting the existing black coal-fired power plants in Australia with commercially available 30% w/w aqueous MEA based CO_2 capture technology for 90% CO_2 emission reduction will add Aus $40 to 45 per MWh (of net power production) to the nominal cost of electricity generation and result into the cost of CO_2 avoidance approximately Aus $60 per tonne of CO_2. The increase in the cost of electricity generation, as a consequence of PCC integration with existing black and brown coal-fired power plants, is dominated (as much as 52%) by the cost of capital (amortisation) associated with retrofitting a capture plant. Such a high level of contribution by the amortised capital charges to the cost of electricity generation clearly indicates that in order to reduce the economic impact of post combustion capture on the power generation sector, the technology development efforts should be directed at reducing the fixed capital cost of the capture plant and reducing its adverse impact on the net power plant efficiency. For the existing power plants, replacing the existing LP turbine with a new LP turbine that is optimised for continuous steam extraction to meet the CO_2 plant duty minimises the adverse impact of integration of post combustion capture, but the power generator will lose the flexibility for electricity generation.

6. Acknowledgement

This project is part of the CSIRO Coal Technology Portfolio and received funding from the Australian Government as part of the Asia-Pacific Partnership on Clean Development and Climate. The views expressed herein are not necessarily the views of the Commonwealth, and the Commonwealth does not accept responsibility for any information or advice contained herein.

Dr Narendra Dave and the co-authors are thankful to the management of Jord International Pty Ltd, NSW, Australia, for sizing and costing air cooled condensers, heat exchangers and CO2 compression intercoolers for this work.

7. References

[1] www.abare.gov.au/publications_html/energy/energy_10/EG10_Apr.pdf

[2] AGO, 2006: Technical guidelines – Generator efficiency standards, Department of Environment and Heritage, Australian Government, ISBN: 1 9212 97 247.

[3] Aresta M., 2003: Carbon dioxide recovery and utilisation, Kluwer Academic Publishers, Netherlands, ISBN: 1-4020-1409-0.

[4] Dave N C, Duffy G J, Edwards, J H and Lowe A., 2000: Evaluation of the options for recovery and disposal/utilisation of CO2 from Australian black coal-fired power plants, ACARP Project Final Report No. C7051.

[5] EPRI Interim Technical Report No: 1000316, December 2000, Evaluation of innovative fossil fuel power plants with CO_2 removal.

[6] Féraud, A., Marocco, L. and Howard, T., 2006: CASTOR Study on Technological Requirements for Flue Gas Clean-Up Prior to CO_2-Capture, presented at GHGT-8 Conference, Trondheim, Norway.

[7] Feron, P.H. M. 2008: Post-Combustion Capture (PCC) R&D and Pilot Plant Operation in Australia, IEA GHG - 11th Post Combustion CO2 Capture Network Meeting, Vienna, Austria, 20-21 May.

[8] GPSA, 1998: Gas Suppliers Association Engineering Data Book, 11th Edition, Section 21, pp.6.

[9] IPCC Special Report, 2005: Carbon dioxide capture and storage, Mertz, B., Davidson, O., de Conninck, H., Loos, M. and Meyer, L. (eds) (Cambridge University Press, UK), pp. 431.

[10] Parsons, E. L., Shelton, W. W. and Lyons, J. L., 2002: Advanced fossil power systems comparison study, Final Report for US/DOE-NETL.

[11] Riemer P., 1993: The capture of CO_2 from fossil fuel fired power stations, IEA GHG R&D Programme Report No. IEAGHG/SR2, December.

[12] US DOE/NETL Technical Report No: 401/110907, November 2007: Carbon dioxide capture from existing coal-fired power plants.

[13] Dave N C, Do T and Palfreyman D., 2008: Assessing post combustion capture for coal-fired power stations in APP countries –New power plants, CSIRO Report ET/IR – 1083.

[14] Dave N C, Do T and Palfreyman D., 2009: Assessing post combustion capture for coal-fired power stations in APP countries –Existing power plants, CSIRO Report ET/IR – 1144.